CONOCOPHILLIPS
Form 10-Q
October 31, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2017

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______ to ______

Commission file number: 001-32395

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

600 North Dairy Ashford, Houston, TX 77079

(Address of principal executive offices) (Zip Code)

281-293-1000

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
Emerging growth company	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The registrant had 1,195,515,824 shares of common stock, $.01 par value, outstanding at September 30, 2017.

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CONOCOPHILLIPS

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PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Consolidated Income Statement **ConocoPhillips**

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Revenues and Other Income				
Sales and other operating revenues	$ **6,688**	6,415	**20,987**	16,884
Equity in earnings (losses) of affiliates	**196**	(60)	**574**	(129)
Gain on dispositions	**246**	51	**2,144**	202
Other income	**65**	110	**143**	149
Total Revenues and Other Income	**7,195**	6,516	23,848	17,106
Costs and Expenses				
Purchased commodities	**2,926**	2,819	**9,040**	7,046
Production and operating expenses	**1,224**	1,526	**3,849**	4,325
Selling, general and administrative expenses	**132**	203	**423**	556
Exploration expenses	**75**	457	**724**	1,572
Depreciation, depletion and amortization	**1,608**	2,425	**5,212**	7,001
Impairments	**6**	123	**6,475**	321
Taxes other than income taxes	**175**	161	**604**	538
Accretion on discounted liabilities	**89**	108	**276**	329
Interest and debt expense	**251**	335	**872**	928
Foreign currency transaction losses	**5**	13	**28**	12
Other expense	**51**		**285**	
Total Costs and Expenses	**6,542**	8,170	**27,788**	22,628
Income (loss) before income taxes	**653**	(1,654)	**(3,940)**	(5,522)
Income tax provision (benefit)	**217**	(628)	**(1,549)**	(1,982)
Net Income (Loss)	**436**	(1,026)	**(2,391)**	(3,540)
Less: net income attributable to noncontrolling interests	**(16)**	(14)	**(43)**	(40)
Net Income (Loss) Attributable to ConocoPhillips	$ **420**	(1,040)	**(2,434)**	(3,580)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic	$ **0.35**	(0.84)	**(1.98)**	(2.88)
Diluted	**0.34**	(0.84)	**(1.98)**	(2.88)
Dividends Paid Per Share of Common Stock *(dollars)*	$ **0.27**	0.25	**0.80**	0.75

Average Common Shares Outstanding *(in thousands)*				
Basic	**1,212,454**	1,245,961	**1,230,742**	1,245,139
Diluted	**1,215,341**	1,245,961	**1,230,742**	1,245,139

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income **ConocoPhillips**

		Millions of Dollars			
		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Income (Loss)	$	**436**	(1,026)	**(2,391)**	(3,540)
Other comprehensive income (loss)					
Defined benefit plans					
Reclassification adjustment for amortization of prior service credit included in net income		**(9)**	(7)	**(28)**	(25)
Net actuarial gain (loss) arising during the period		**13**	(31)	**(26)**	(331)
Reclassification adjustment for amortization of net actuarial losses included in net income		**49**	47	**205**	229
Nonsponsored plans*			2		2
Income taxes on defined benefit plans		**(18)**	(2)	**(52)**	51
Defined benefit plans, net of tax		**35**	9	**99**	(74)
Unrealized holding gain on securities		**551**		**127**	
Income taxes on unrealized holding gain on securities		**(45)**		**(45)**	
Unrealized gain on securities, net of tax		**506**		**82**	
Foreign currency translation adjustments		**509**	(82)	**720**	877
Foreign currency translation adjustments, net of tax		**509**	(82)	**720**	877
Other Comprehensive Income (Loss), Net of Tax		**1,050**	(73)	**901**	803
Comprehensive Income (Loss)		**1,486**	(1,099)	**(1,490)**	(2,737)
Less: comprehensive income attributable to noncontrolling interests		**(16)**	(14)	**(43)**	(40)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	**1,470**	(1,113)	**(1,533)**	(2,777)

**Plans for which ConocoPhillips is not the primary obligor-primarily those administered by equity affiliates.*

See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

		Millions of Dollars	
		September 30 2017	December 31 2016
Assets			
Cash and cash equivalents	$	**6,911**	3,610
Short-term investments		**2,696**	50
Accounts and notes receivable (net of allowance of $4 million in 2017 and $5 million in 2016)		**3,222**	3,249
Accounts and notes receivable related parties		**142**	165
Investment in Cenovus Energy		**2,084**	
Inventories		**1,023**	1,018
Prepaid expenses and other current assets		**876**	517
Total Current Assets		**16,954**	8,609
Investments and long-term receivables		**9,696**	21,091
Loans and advances related parties		**461**	581
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $64,115 million in 2017 and $73,075 million in 2016)		**46,669**	58,331
Other assets		**1,081**	1,160
Total Assets	$	**74,861**	89,772
Liabilities			
Accounts payable	$	**3,378**	3,631
Accounts payable related parties		**38**	22
Short-term debt		**1,331**	1,089
Accrued income and other taxes		**1,005**	484
Employee benefit obligations		**528**	689
Other accruals		**851**	994
Total Current Liabilities		**7,131**	6,909
Long-term debt		**19,673**	26,186
Asset retirement obligations and accrued environmental costs		**7,763**	8,425
Deferred income taxes		**6,262**	8,949
Employee benefit obligations		**1,903**	2,552
Other liabilities and deferred credits		**1,417**	1,525
Total Liabilities		**44,149**	54,546
Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2017 1,785,195,738 shares; 2016 1,782,079,107 shares)			
Par value		**18**	18
Capital in excess of par		**46,595**	46,507
Treasury stock (at cost: 2017 589,679,914 shares; 2016 544,809,771 shares)		**(38,951)**	(36,906)
Accumulated other comprehensive loss		**(5,292)**	(6,193)
Retained earnings		**28,130**	31,548
Total Common Stockholders Equity		**30,500**	34,974
Noncontrolling interests		**212**	252

Total Equity	**30,712**	35,226
Total Liabilities and Equity	**$ 74,861**	89,772

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars Nine Months Ended September 30	
	2017	2016
Cash Flows From Operating Activities		
Net loss	$ **(2,391)**	(3,540)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	**5,212**	7,001
Impairments	**6,475**	321
Dry hole costs and leasehold impairments	**435**	1,010
Accretion on discounted liabilities	**276**	329
Deferred taxes	**(2,770)**	(2,152)
Distributions received greater than equity losses (undistributed equity earnings)	**(193)**	414
Gain on dispositions	**(2,144)**	(202)
Other	**(367)**	(50)
Working capital adjustments		
Decrease in accounts and notes receivable	**65**	1,112
Decrease (increase) in inventories	**(15)**	22
Decrease (increase) in prepaid expenses and other current assets	**(12)**	46
Decrease in accounts payable	**(212)**	(515)
Increase (decrease) in taxes and other accruals	**237**	(836)
Net Cash Provided by Operating Activities	**4,596**	2,960
Cash Flows From Investing Activities		
Capital expenditures and investments	**(3,074)**	(3,870)
Working capital changes associated with investing activities	**(18)**	(401)
Proceeds from asset dispositions	**13,740**	419
Net purchases of short-term investments	**(2,583)**	(229)
Collection of advances/loans related parties	**115**	108
Other	**51**	61
Net Cash Provided by (Used in) Investing Activities	**8,231**	(3,912)
Cash Flows From Financing Activities		
Issuance of debt		4,594
Repayment of debt	**(6,594)**	(839)
Issuance of company common stock	**(65)**	(52)
Repurchase of company common stock	**(2,045)**	
Dividends paid	**(986)**	(940)
Other	**(80)**	(93)
Net Cash Provided by (Used in) Financing Activities	**(9,770)**	2,670
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**244**	4

Net Change in Cash and Cash Equivalents		**3,301**	1,722
Cash and cash equivalents at beginning of period		**3,610**	2,368
Cash and Cash Equivalents at End of Period	**$**	**6,911**	4,090

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements **ConocoPhillips**

Note 1 Basis of Presentation

The interim-period financial information presented in the financial statements included in this report is unaudited and, in the opinion of management, includes all known accruals and adjustments necessary for a fair presentation of the consolidated financial position of ConocoPhillips and its results of operations and cash flows for such periods. All such adjustments are of a normal and recurring nature unless otherwise disclosed. Certain notes and other information have been condensed or omitted from the interim financial statements included in this report. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and notes included in our 2016 Annual Report on Form 10-K.

Note 2 Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Australia Pacific LNG Pty Ltd (APLNG)

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as liquefied natural gas (LNG) processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of September 30, 2017, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 5 Investments, Loans and Long-Term Receivables, and Note 11 Guarantees, for additional information.

Marine Well Containment Company, LLC (MWCC)

MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a Founding Member and exercise significant influence through our permanent seat on the ten-member Executive Committee responsible for overseeing the affairs of MWCC. In 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

At September 30, 2017, the carrying value of our equity method investment in MWCC was $141 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

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Note 3 Inventories

Inventories consisted of the following:

	Millions of Dollars	
	September 30 2017	December 31 2016
Crude oil and natural gas	$ **465**	418
Materials and supplies	**558**	600
	$ **1,023**	1,018

Inventories valued on the last-in, first-out (LIFO) basis totaled $297 million and $269 million at September 30, 2017 and December 31, 2016, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $90 million and $104 million at September 30, 2017 and December 31, 2016, respectively.

Note 4 Assets Held for Sale or Sold

Assets Held for Sale

On June 28, 2017, we signed a definitive agreement with an affiliate of Miller Thomson & Partners LLC to sell our interests in the Barnett for $305 million in cash, subject to customary adjustments. The transaction is subject to specific conditions precedent being satisfied, including regulatory approval, and is expected to close in the fourth quarter of 2017. We recorded a before-tax impairment of $566 million in the second quarter of 2017 to reduce the carrying value of our investment to fair value and an additional impairment of $2 million was recorded in the third quarter of 2017. As of September 30, 2017, our Barnett interests had a net carrying value of approximately $296 million and were considered held for sale resulting in the reclassification of $344 million of properties, plants and equipment (PP&E) to Prepaid expenses and other current assets and $49 million of noncurrent liabilities, primarily asset retirement obligations, to Other accruals on our consolidated balance sheet. The before-tax loss associated with our interests in the Barnett, including the $566 million and $2 million impairments noted above, was $575 million and $55 million for the nine-month periods ended September 30, 2017 and September 30, 2016, respectively. The Barnett results of operations are reported within our Lower 48 segment.

Assets Sold

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11 billion in cash after customary adjustments, including $600 million related to environmental claims, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The cash proceeds are included in the Cash Flows From Investing Activities section of our consolidated statement of cash flows. The value of the shares at closing was $1.96 billion based on a price of $9.41 per share on the New York Stock Exchange. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel.

At closing, the carrying value of our equity investment in FCCL was $8.9 billion. The carrying value of our interest in the western Canada gas assets was $1.9 billion consisting primarily of $2.6 billion of PP&E, partly offset by asset retirement obligations of $585 million and approximately $100 million of environmental and other accruals. A before-tax gain of $1.85 billion was included in the Gain on disposition line on our consolidated income statement for the second quarter of 2017. An additional before-tax gain of $281 million was recognized in the third quarter of 2017. We reported before-tax losses of $26 million and $444 million for the western Canada gas producing properties for the nine-month periods ending September 30, 2017 and

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September 30, 2016, respectively. We reported before-tax equity earnings of $197 million and a before-tax equity loss of $37 million for FCCL for the same periods, respectively. Both FCCL and the western Canada gas assets were reported within our Canada segment.

For more information on the Canada disposition and our investment in Cenovus Energy see Note 6 Investment in Cenovus Energy, Note 14 Fair Value Measurement, and Note 15 Accumulated Other Comprehensive Income (Loss).

On July 31, 2017, we completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company for $2.5 billion in cash after customary adjustments, and recognized a loss on disposition of $22 million. The $2.5 billion of cash proceeds are included in the Cash Flows From Investing Activities section of our consolidated statement of cash flows. The transaction includes a contingent payment of up to $300 million. The six-year contingent payment is effective beginning January 1, 2018, and is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units.

In the second quarter of 2017, we recorded a before-tax impairment of $3.3 billion to reduce the carrying value of our interests in the San Juan Basin to fair value. At the time of disposition, the San Juan Basin interests had a net carrying value of approximately $2.5 billion, consisting of $2.9 billion of PP&E and $406 million of liabilities, primarily asset retirement obligations. The before-tax loss associated with our interests in the San Juan Basin, including both the $3.3 billion impairment and $22 million loss on disposition noted above, was $3.2 billion and $226 million for the nine-month periods ended September 30, 2017 and September 30, 2016, respectively. The San Juan Basin results of operations are reported within our Lower 48 segment.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments, and recognized a before-tax loss on disposition of $28 million. The proceeds are included in the Cash Flows From Investing Activities section of our consolidated statement of cash flows. At the time of the disposition, the carrying value of our interest was $206 million, consisting primarily of $279 million of PP&E and $72 million of asset retirement obligations. Including the $28 million loss on disposition noted above, we reported before-tax losses for the Panhandle properties of $16 million and $28 million for the nine months ended September 30, 2017 and September 30, 2016, respectively. The Panhandle results are reported within our Lower 48 segment.

Note 5 Investments, Loans and Long-Term Receivables

APLNG

APLNG s $8.5 billion project finance facility consists of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. All amounts have been drawn from the facility. APLNG made its first principal and interest repayment in March 2017 and will continue to make bi-annual payments until March 2029. At September 30, 2017, a balance of $7.9 billion was outstanding on the facility. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieved financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. In August 2017, we reached financial completion for Train 2, which removed the remaining guarantee. See Note 11 Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 2 Variable Interest Entities (VIEs), for additional information.

During the first and second quarters of 2017, the outlook for crude oil prices deteriorated, and as a result of significantly reduced price outlooks, the estimated fair value of our investment in APLNG declined to an amount below carrying value. Based on a review of the facts and circumstances surrounding this decline in

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fair value, we concluded in the second quarter of 2017 the impairment was other than temporary under the guidance of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 323, Investments Equity Method and Joint Ventures, and the recognition of an impairment of our investment to fair value was necessary. Accordingly, we recorded a noncash $2,384 million, before- and after-tax impairment in our second-quarter 2017 results. Fair value was estimated based on an internal discounted cash flow model using estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies (long-term), costs, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants. The impairment was included in the Impairments line on our consolidated income statement.

At September 30, 2017, the carrying value of our equity method investment in APLNG was $7,661 million. The balance is included in the Investments and long-term receivables line item on our consolidated balance sheet.

FCCL

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. For additional information on the Canada disposition and our investment in Cenovus Energy, see Note 4 Assets Held for Sale or Sold and Note 6 Investment in Cenovus Energy.

Loans and Long-Term Receivables

As part of our normal ongoing business operations, and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans made to certain affiliated and non-affiliated companies. At September 30, 2017, significant loans to affiliated companies included $581 million in project financing to Qatar Liquefied Gas Company Limited (3) (QG3).

The long-term portion of these loans is included in the Loans and advances related parties line on our consolidated balance sheet, while the short-term portion is in Accounts and notes receivable related parties.

Note 6- Investment in Cenovus Energy

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares. See Note 4 Assets Held for Sale or Sold, for additional information on the Canada disposition.

At closing, the fair value and cost basis of our investment in 208 million Cenovus Energy common shares was $1.96 billion based on a price of $9.41 per share on the New York Stock Exchange. Our ownership approximates to 16.9 percent of issued and outstanding Cenovus common shares, and under an investor agreement with Cenovus Energy, we have agreed not to transfer any of our Cenovus Energy common shares until six months from the closing date (the Lock-up Termination Date).

We have classified our investment as an available-for-sale equity security on our consolidated balance sheet and, as of September 30, 2017, our investment is carried at fair value of $2.08 billion, reflecting the closing price of Cenovus Energy shares on the New York Stock Exchange of $10.02 per share. The carrying value reflects a before-tax unrealized gain of $127 million and an after-tax unrealized gain of $82 million over our cost basis of $1.96 billion. The unrealized gain is reported as a component of accumulated other comprehensive loss. See Note 14 Fair Value Measurement, for additional information. Following the Lock-up Termination Date, we intend to decrease our investment over time through market transactions, private agreements or otherwise.

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Note 7 Suspended Wells and Other Exploration Expenses

The capitalized cost of suspended wells at September 30, 2017, was $872 million, a decrease of $191 million from $1,063 million at year-end 2016. Two suspended wells in Shenandoah in the Gulf of Mexico totaling $94 million, one suspended well in Alaska totaling $17 million, and one suspended well in Malaysia totaling $23 million were charged to dry hole expense during the first nine months of 2017 relating to exploratory well costs capitalized for a period greater than one year as of December 31, 2016.

We reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we recorded a before-tax charge of $43 million net in the first quarter of 2017. This charge is included in the Exploration expenses line on our consolidated income statement.

Note 8 Impairments

During the three- and nine-month periods ended September 30, 2017 and 2016, we recognized before-tax impairment charges within the following segments:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Alaska	$ **1**		**178**	
Lower 48	**3**	1	**3,888**	61
Canada		60	**18**	60
Europe and North Africa	**2**	20	**7**	157
Asia Pacific and Middle East		42	**2,384**	43
	$ **6**	123	**6,475**	321

In the nine-month period of 2017, our Lower 48 segment included impairments of $3,888 million primarily due to certain developed properties which were written down to fair value less costs to sell. See Note 4 Assets Held for Sale or Sold, for additional information on our dispositions. Additionally, the nine-month period of 2017 included the impairment of our APLNG investment reported within the Asia Pacific and Middle East segment. For more information, see the APLNG section of Note 5 Investments, Loans and Long-Term Receivables. The nine-month period also included an impairment in our Alaska segment in the first quarter of 2017 of $174 million for the associated PP&E carrying value of our small interest in a nonoperated producing property.

In October 2017, we expect to record an estimated $60 million before-tax impairment of a gas processing plant in Norway, primarily due to restructured ownership and a change in commercial premises. This impairment will be reflected in our year-end results within our Europe and North Africa segment.

In the three- and nine-month periods ended September 30, 2016, our Canada and Asia Pacific and Middle East segments included impairments of $60 million and $42 million, respectively, primarily related to certain developed properties in central Alberta and offshore Indonesia, which were written down to fair value less costs to sell. Our Europe and North Africa segment included impairments of $20 million in the three-month period ended September 30, 2016, primarily as a result of a canceled project and lower natural gas prices, both in the United Kingdom. In the nine-month period of 2016, our Europe and North Africa segment included impairments of $157 million, primarily as a result of lower natural gas prices in the United Kingdom. Our Lower 48 segment included impairments of $61 million before-tax in the nine-month period of 2016, primarily as a result of lower natural gas prices and increased asset retirement obligation estimates.

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The charges discussed below are included in the Exploration expenses line on our consolidated income statement and are not reflected in the table above.

Exploration expenses in the three- and nine-month periods of 2017 and 2016 were aligned with our decision announced in 2015 to reduce deepwater exploration spending.

In the first quarter of 2017, we recorded a before-tax impairment of $51 million for the associated carrying value of capitalized undeveloped leasehold costs of Shenandoah in deepwater Gulf of Mexico following the suspension of appraisal activity by the operator.

In the second quarter of 2016, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. In the first quarter of 2016, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect, and the majority of a $79 million impairment in deepwater Gulf of Mexico, mainly as a result of changes in the estimated market value following the completion of an initial marketing effort.

Note 9 Debt

As of September 30, 2017, our revolving credit facility, expiring in June 2019, was $6.75 billion. The credit facility supports two commercial paper programs: the ConocoPhillips $6.25 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $500 million program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days.

At September 30, 2017 and December 31, 2016, we had no direct outstanding borrowings under the revolving credit facility and no letters of credit. We had no commercial paper outstanding at September 30, 2017 or December 31, 2016, under both the ConocoPhillips and the ConocoPhillips Qatar Funding Ltd. commercial paper programs. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at September 30, 2017.

In the first quarter of 2017, we made a prepayment of $805 million on our floating rate term loan facility due in 2019. In the third quarter of 2017, we prepaid the remaining balance of $645 million.

During the nine-month period of 2017, we redeemed a total $4.8 billion of debt as described below.

In the second quarter of 2017, we redeemed $3.0 billion of debt across the following instruments:

- 6.65% Debentures due 2018 with principal of $297 million.
- 5.75% Notes due 2019 with principal of $2.25 billion (partial redemption of $1.7 billion).
- 6.00% Notes due 2020 with principal of $1.0 billion.

In the third quarter of 2017, we redeemed $1.8 billion of debt across the following instruments:

- 5.20% Notes due 2018 with principal of $500 million.
- 1.50% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $550 million.

We incurred premiums above book value to redeem the debt instruments of $234 million and $50 million in the second and third quarter of 2017, respectively. These costs are reported in the Other expense line on our consolidated income statement.

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In October 2017, we gave notice to make a partial redemption of $250 million on the $1.25 billion 4.20% Notes due in 2021. The prepayment will occur in the fourth quarter of 2017, and we expect to incur approximately $20 million in premiums above book value, subject to pricing, related to this redemption when paid.

At September 30, 2017, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the Long-term debt line on our consolidated balance sheet.

Note 10 Noncontrolling Interests

Activity attributable to common stockholders equity and noncontrolling interests for the first nine months of 2017 and 2016 was as follows:

	Millions of Dollars					
	2017			2016		
	Common Stockholders Equity	Non-Controlling Interest	Total Equity	Common Stockholders Equity	Non-Controlling Interest	Total Equity
Balance at January 1	**$ 34,974**	**252**	**35,226**	39,762	320	40,082
Net income (loss)	**(2,434)**	**43**	**(2,391)**	(3,580)	40	(3,540)
Dividends	**(986)**		**(986)**	(940)		(940)
Repurchase of company common stock	**(2,045)**		**(2,045)**			
Distributions to noncontrolling interests		**(84)**	**(84)**		(75)	(75)
Other changes, net*	**991**	**1**	**992**	928	1	929
Balance at September 30	**$ 30,500**	**212**	**30,712**	36,170	286	36,456

**Includes components of other comprehensive income (loss), which are disclosed separately in the Consolidated Statement of Comprehensive Income.*

Note 11 Guarantees

At September 30, 2017, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees

At September 30, 2017, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing September 2017 exchange rates:

We guaranteed APLNG s performance with regard to a construction contract executed in connection with APLNG s issuance of the Train 1 and Train 2 Notices to Proceed. Our maximum potential amount of future payments related to this guarantee became immaterial in the second quarter of 2017.

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We issued a construction completion guarantee related to the third-party project financing secured by APLNG. In October 2016, we reached financial completion for Train 1, releasing a portion of our guarantee. In August 2017, the two-train project finance lenders test was completed, releasing the remaining guarantee.

During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 12 years. Our maximum exposure under this guarantee is approximately $200 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At September 30, 2017, the carrying value of this guarantee was approximately $14 million.

In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of up to 25 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $1 billion ($1.75 billion in the event of intentional or reckless breach), and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project s continued development. The guarantees have remaining terms of up to 28 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $160 million and would become payable if APLNG does not perform.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $780 million, which consist primarily of guarantees of the residual value of leased office buildings, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture s project finance reserve accounts. These guarantees have remaining terms of up to six years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at September 30, 2017, was approximately $100 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at September 30, 2017, were approximately $40 million of environmental accruals for known contamination that are included in the Asset retirement obligations and accrued environmental costs line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 12 Contingencies and Commitments.

On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream businesses formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.28 billion. At September 30, 2017, the carrying value of this guarantee is approximately $98 million and the remaining term is seven years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

Note 12 Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated but no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to factors such as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated.

At September 30, 2017, our balance sheet included a total environmental accrual of $182 million, compared with $247 million at December 31, 2016, for remediation activities in the United States and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years. In the future, we may be involved in additional environmental assessments, cleanups and proceedings.

Legal Proceedings

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at September 30, 2017, we had performance obligations secured by letters of credit of $286 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela s actions. Separate arbitrations for contractual compensation against PDVSA are also pending before International Chamber of Commerce (ICC) arbitration tribunals. In addition,

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ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID tribunal, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed supplemental counterclaims asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington, finding that Ecuador s seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. In February 2017, the tribunal unanimously awarded Burlington $380 million for Ecuador s unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for limited environmental and infrastructure impacts associated with the operations of Burlington and its co-venturer. Ecuador filed a request for annulment of this decision with ICSID, triggering a provisional stay of enforcement of the award. On August 31, the ICSID Annulment Committee issued a decision terminating the provisional stay. The annulment proceeding is ongoing.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. The arbitration is being conducted under the United Nations Commission on International Trade Laws (UNCITRAL) rules using a three-person tribunal. The arbitration is ongoing.

In June 2017, FAR Ltd. initiated arbitration before the ICC against ConocoPhillips Senegal B.V. in connection with the sale of ConocoPhillips Senegal B.V. to Woodside Energy Holdings (Senegal) Limited in 2016. The arbitral tribunal is in the process of being constituted.

Note 13 Derivative and Financial Instruments

Derivative Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

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The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

	Millions of Dollars	
	September 30 2017	December 31 2016
Assets		
Prepaid expenses and other current assets	$ **170**	268
Other assets	**32**	44
Liabilities		
Other accruals	**167**	300
Other liabilities and deferred credits	**23**	34

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Sales and other operating revenues	$ **17**	11	**120**	(155)
Other income	**(1)**	1	**(1)**	(1)
Purchased commodities	**(19)**	7	**(88)**	136

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

	Open Position Long/(Short)	
	September 30 2017	December 31 2016
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(33)**	(31)
Basis	**42**	2

Foreign Currency Exchange Derivatives

We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related and foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates. We do not elect hedge accounting on our foreign currency exchange derivatives.

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The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

		Millions of Dollars	
		September 30 2017	December 31 2016
Assets			
Prepaid expenses and other current assets	**$**	**1**	1
Liabilities			
Other accruals			168

The (gains) losses from foreign currency exchange derivatives incurred, and the line item where they appear on our consolidated income statement were:

		Millions of Dollars			
		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Foreign currency transaction (gains) losses	**$**	**(1)**	35	**2**	218

We had the following net notional position of outstanding foreign currency exchange derivatives:

		In Millions Notional Currency	
		September 30 2017	December 31 2016
Sell U.S. dollar, buy other currencies*	USD	**26**	13
Buy U.S. dollar, sell other currencies**	USD		25
Buy British pound, sell other currencies***	GBP	**3**	1,069
Sell British pound, buy Norwegian krone	GBP		51

**Primarily Canadian dollar.*

***Primarily British pound.*

****Primarily Euro and Canadian dollar.*

Financial Instruments

We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments in which we currently invest include:

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.

These financial instruments appear in the "Cash and cash equivalents" line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these financial instruments are included in the "Short-term investments" line on our consolidated balance sheet.

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	Millions of Dollars Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	September 30 2017	December 31 2016	**September 30 2017**	December 31 2016
Cash	**$ 925**	623		
Time deposits				
Remaining maturities from 1 to 90 days	**5,462**	2,987	**1,103**	39
Remaining maturities from 91 to 180 days			**74**	11
Commercial paper				
Remaining maturities from 1 to 90 days	**524**		**1,320**	
Remaining maturities from 91 to 180 days			**199**	
	$ 6,911	**3,610**	**2,696**	**50**

Credit Risk

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, government money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit-risk-related contingent features that were in a liability position on September 30, 2017 and December 31, 2016, was $39 million and $42 million, respectively. For these instruments, no collateral was posted as of September 30, 2017 or December 31, 2016. If our credit rating had been downgraded below investment grade on September 30, 2017, we would be required to post $39 million of additional collateral, either with cash or letters of credit.

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Note 14 Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
Level 2: Inputs other than quoted prices that are directly or indirectly observable.
Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1 during 2017 or 2016.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. This also includes our investment in common shares of Cenovus Energy, currently subject to a trading restriction, which is valued using quotes for shares on the New York Stock Exchange. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management s best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

		Millions of Dollars							
		September 30, 2017				December 31, 2016			
		Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets									
Investment in Cenovus Energy	**$**		**2,084**		**2,084**				
Commodity derivatives		**109**	**69**	**24**	**202**	194	96	22	312
Total assets	**$**	**109**	**2,153**	**24**	**2,286**	194	96	22	312
Liabilities									
Commodity derivatives	**$**	**112**	**61**	**17**	**190**	207	105	22	334
Total liabilities	**$**	**112**	**61**	**17**	**190**	207	105	22	334

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The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of setoff exists.

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
September 30, 2017						
Assets	**$ 202**	**118**	**84**	**4**	**4**	**76**
Liabilities	**190**	**118**	**72**	**9**	**3**	**60**
December 31, 2016						
Assets	$ 312	221	91		5	86
Liabilities	334	221	113	12	12	89

At September 30, 2017 and December 31, 2016, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Non-Recurring Fair Value Measurement

The following table summarizes the fair value hierarchy by major category and date of remeasurement for assets accounted for at fair value on a non-recurring basis:

	Millions of Dollars			
		Fair Value Measurements Using		
	Fair Value	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
June 30, 2017 (remeasurement date)				
Net PP&E (held for sale)	**$ 2,830**	**2,830**		**3,882**
Cost and equity method investments	**7,656**		**7,656**	**2,384**

During the second quarter of 2017, net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its negotiated selling price. For additional information see Note 4 Assets Held for Sale or Sold.

During the second quarter of 2017, our equity method investment in APLNG was determined to have fair value below its carrying value, and the impairment was considered to be other than temporary. See the APLNG section of Note 5 Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

Reported Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value. Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances related parties.

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- Investment in Cenovus Energy shares: See Note 6 Investment in Cenovus Energy, for a discussion of the carrying value and fair value of our investment in Cenovus Energy shares.
- Loans and advances related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 5 Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

	Millions of Dollars			
	Carrying Amount		Fair Value	
	September 30 2017	December 31 2016	**September 30 2017**	December 31 2016
Financial assets				
Investment in Cenovus Energy	**$ 2,084**		**2,084**	
Commodity derivatives	**80**	91	**80**	91
Total loans and advances related parties	**583**	701	**583**	701
Financial liabilities				
Total debt, excluding capital leases	**20,181**	26,423	**23,451**	29,307
Commodity derivatives	**63**	101	**63**	101

Note 15 Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive loss in the equity section of our consolidated balance sheet included:

	Millions of Dollars			
	Defined Benefit Plans	Net Unrealized Gain on Securities	Foreign Currency Translation	Accumulated Other Comprehensive Income (Loss)
December 31, 2016	$ (547)		(5,646)	(6,193)
Other comprehensive income	**99**	**82**	**720**	**901**
September 30, 2017	**$ (448)**	**82**	**(4,926)**	**(5,292)**

There were no items within accumulated other comprehensive loss related to noncontrolling interests.

The following table summarizes reclassifications out of accumulated other comprehensive loss:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Defined benefit plans	$ **26**	27	**116**	132
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	*$ **14***	*13*	***61***	*72*

See Note 17 Employee Benefit Plans, for additional information.

Note 16 Cash Flow Information

	Millions of Dollars	
	Nine Months Ended September 30	
	2017	2016
Cash Payments (Receipts)		
Interest	$ **918**	854
Income taxes*	**574**	(339)
Net Sales (Purchases) of Short-Term Investments		
Short-term investments purchased	$ **(4,999)**	(1,704)
Short-term investments sold	**2,416**	1,475
	$ **(2,583)**	(229)

**Net of $569 million in 2016 related to refunds received from the Internal Revenue Service.*

During the first quarter of 2017, we recognized a $180 million adverse cash impact from the settlement of cross-currency swap transactions which is included in the Cash Flows From Operating Activities section of our consolidated statement of cash flow.

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Note 17 Employee Benefit Plans

Pension and Postretirement Plans

		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2017		2016		**2017**	2016
		U.S.	Int l.	U.S.	Int l.		
Components of Net Periodic Benefit Cost							
Three Months Ended September 30							
Service cost	$	**21**	**20**	27	19		
Interest cost		**29**	**27**	32	30	**3**	3
Expected return on plan assets		**(32)**	**(41)**	(34)	(39)		
Amortization of prior service cost (credit)		**1**	**(1)**	2	(1)	**(9)**	(9)
Recognized net actuarial loss (gain)		**17**	**12**	22	6	**(1)**	
Settlements		**21**		22			
Curtailment Loss				14			1
Net periodic benefit cost	$	**57**	**17**	85	15	**(7)**	(5)
Nine Months Ended September 30							
Service cost	$	**67**	**59**	82	59	**1**	1
Interest cost		**90**	**78**	104	93	**7**	10
Expected return on plan assets		**(97)**	**(119)**	(112)	(121)		
Amortization of prior service cost (credit)		**3**	**(4)**	4	(4)	**(27)**	(26)
Recognized net actuarial loss (gain)		**53**	**36**	64	20	**(2)**	(1)
Settlements		**118**		149			
Curtailment Loss				14			1
Net periodic benefit cost	$	**234**	**50**	305	47	**(21)**	(15)

During the first nine months of 2017, we contributed $783 million to our domestic benefit plans and $89 million to our international benefit plans. In 2017, we expect to contribute approximately $800 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $120 million to our international qualified and nonqualified pension and postretirement benefit plans.

We recognized a proportionate share of prior actuarial losses from other comprehensive income as pension settlement expense of $21 million and $118 million during the three- and nine-month periods ended September 30, 2017, respectively. In conjunction with the recognition of pension settlement expense, the fair market values of U.S. pension plan assets were updated, and the pension benefit obligations of the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan were remeasured as of September 30, 2017. As part of the remeasurement, the expected rate of return on the U.S. qualified pension plan assets was reduced from 6.8 percent at January 1, 2017, to 5.8 percent at September 30, 2017.

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Severance Accrual

As a result of selling our 50 percent nonoperated interest in the FCCL Partnership and the majority of our western Canada gas assets, as well as our interests in the San Juan Basin, a reduction in our overall employee workforce began during the second quarter of 2017. Severance accruals of $7 million and $62 million were recorded during the three- and nine-month periods ended September 30, 2017, respectively. The following table summarizes our severance accrual activity for the nine-month period ended September 30, 2017:

	Millions of Dollars
Balance at December 31, 2016	$ 80
Accruals	**62**
Benefit payments	**(84)**
Foreign currency translation adjustments	**2**
Balance at September 30, 2017	**$ 60**

Of the remaining balance at September 30, 2017, $36 million is classified as short-term.

Note 18 Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Operating revenues and other income	$ **24**	41	**83**	96
Purchases	**26**	26	**74**	75
Operating expenses and selling, general and administrative expenses	**16**	20	**42**	48
Net interest (income) expense*	**(4)**	(3)	**(10)**	(9)

**We paid interest to, or received interest from, various affiliates. See Note 5 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

Note 19 Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents and short-term investments.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Intersegment sales are at prices that approximate market.

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Analysis of Results by Operating Segment

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Sales and Other Operating Revenues				
Alaska	$ **932**	925	**3,010**	2,639
Lower 48	**3,102**	2,993	**9,422**	7,533
Intersegment eliminations	**(2)**	(3)	**(7)**	(15)
Lower 48	**3,100**	2,990	**9,415**	7,518
Canada	**699**	615	**2,357**	1,431
Intersegment eliminations	**(155)**	(73)	**(330)**	(138)
Canada	**544**	542	**2,027**	1,293
Europe and North Africa	**1,110**	946	**3,564**	2,605
Asia Pacific and Middle East	**959**	942	**2,877**	2,676
Corporate and Other	**43**	70	**94**	153
Consolidated sales and other operating revenues	$ **6,688**	6,415	**20,987**	16,884
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$ **103**	59	**291**	204
Lower 48	**(97)**	(491)	**(2,995)**	(2,082)
Canada	**280**	(314)	**2,607**	(783)
Europe and North Africa	**85**	163	**379**	132
Asia Pacific and Middle East	**396**	(87)	**(1,540)**	(20)
Other International	**(20)**	(47)	**(77)**	(100)
Corporate and Other	**(327)**	(323)	**(1,099)**	(931)
Consolidated net income (loss) attributable to ConocoPhillips	$ **420**	(1,040)	**(2,434)**	(3,580)

	Millions of Dollars	
	September 30 2017	December 31 2016
Total Assets		
Alaska	$ **12,094**	12,314
Lower 48	**14,376**	22,673
Canada	**6,281**	17,548
Europe and North Africa	**12,066**	11,727
Asia Pacific and Middle East	**17,094**	20,451
Other International	**122**	97

Corporate and Other	**12,828**	4,962
Consolidated total assets	**$ 74,861**	89,772

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Note 20 Income Taxes

Our effective tax rates for the third quarter and nine-month period ended September 30, 2017, were 33 percent and 39 percent, respectively, compared with 38 percent and 36 percent for the same periods of 2016. The amounts of U.S. and foreign income (loss) from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes were:

	Millions of Dollars				Percent of Pre-Tax Income (Loss)			
	Three Months Ended September 30		Nine Months Ended September 30		Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Income (loss) from continuing operations before income taxes								
United States	$ **(197)**	(1,001)	**(5,259)**	(3,965)	**(30.2)%**	60.5	**133.5**	71.8
Foreign	**850**	(653)	**1,319**	(1,557)	**130.2**	39.5	**(33.5)**	28.2
	$ **653**	(1,654)	**(3,940)**	(5,522)	**100.0%**	100.0	**100.0**	100.0
Federal statutory income tax	$ **228**	(578)	**(1,379)**	(1,932)	**34.9%**	34.9	**35.0**	35.0
Non-U.S. effective tax rates	**137**	147	**503**	320	**21.0**	(8.9)	**(12.8)**	(5.8)
U.K. rate change		(138)		(138)		8.3		2.5
Canada disposition	**(8)**		**(1,176)**		**(1.2)**		**29.8**	
Recovery of outside basis	**(118)**	(15)	**(957)**	(38)	**(18.1)**	0.9	**24.3**	0.7
Adjustment to tax reserves	**(17)**		**764**		**(2.6)**		**(19.4)**	
APLNG impairment			**834**				**(21.2)**	
State income tax	**14**	(15)	**(74)**	(126)	**2.1**	0.9	**1.9**	2.3
Enhanced oil recovery credit	**(5)**	(28)	**(49)**	(62)	**(0.8)**	1.7	**1.2**	1.1
Other	**(14)**	(1)	**(15)**	(6)	**(2.1)**	0.2	**0.4**	0.1
	$ **217**	(628)	**(1,549)**	(1,982)	**33.2%**	38.0	**39.3**	35.9

Our effective tax rate for the three- and nine-month periods ended September 30, 2017, was favorably impacted by a tax benefit of $114 million related to our prior decision to exit Nova Scotia deepwater exploration. This benefit is included in the Recovery of Outside Tax Basis line of the table above.

The impairment of our APLNG investment in the second quarter of 2017 did not generate a tax benefit. See the APLNG section of Note 5 Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

Our effective tax rate for the nine-month period ended September 30, 2017, was favorably impacted by a tax benefit of $1,176 million associated with our Canada disposition. The benefit was primarily associated with a deferred tax recovery related to the Canadian capital gains exclusion component of the transaction and the recognition of previously unrealizable Canadian capital asset tax basis. The disposition, along with the associated restructuring of our Canadian operations, may generate an additional tax benefit of $822 million related to the recovery of outside basis. However, since we believe it is not likely we will receive a corresponding cash tax savings of this amount, the benefit has been offset by a full reserve. See Note 4 Assets Held for Sale or Sold, for additional information on our Canada disposition.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, a $138 million net tax benefit resulting from re-measurement of deferred tax liabilities at January 1, 2016, and application of the new rate through September 30, 2016, is reflected in the Income tax benefit line on our consolidated income statement.

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Note 21 New Accounting Standards

In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, Revenue Recognition, and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, Deferral of the Effective Date, which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach.

ASU No. 2014-09 was amended in March 2016 by the provisions of ASU No. 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), in April 2016 by the provisions of ASU No. 2016-10, Identifying Performance Obligations and Licensing, in May 2016 by the provisions of ASU No. 2016-12, Narrow-Scope Improvements and Practical Expedients, and in December 2016 by the provisions of ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers.

We will adopt the provisions of ASU No. 2014-09, as amended, with effect from January 1, 2018, and have elected not to early adopt the standard. We intend to adopt the new standard using the modified retrospective approach which we will apply only to contracts within the scope of the standard that are not complete at the date of initial application. Under this approach, we will apply the guidance retrospectively only to the most current period presented in the financial statements. We continue to assess the impact of adoption of the standard on our current accounting policies and revenue-related disclosures. The impact to our financial statements is expected to be immaterial.

In January 2016, the FASB issued ASU No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities (ASU No. 2016-01), to meet its objective of providing more decision-useful information about financial instruments. The ASU, among other things, requires entities to record the changes in fair value of equity investments, other than investments accounted for using the equity method, within net income. Under this ASU, entities will no longer be able to recognize unrealized holding gains and losses on available-for-sale securities in other comprehensive income. The ASU also requires additional disclosures relating to fair value measurement categories for financial assets and liabilities and eliminates certain disclosure requirements related to financial instruments measured at amortized cost. ASU No. 2016-01 is effective for interim and annual periods beginning after December 15, 2017, and the ASU should be adopted using a cumulative-effect adjustment to retained earnings as of the date of adoption.

Upon adoption of the standard, we will make a cumulative-effect adjustment to reclassify the accumulated unrealized holding gains and losses related to our investment in Cenovus Energy from other comprehensive income to retained earnings, and from the date of adoption, we will begin reporting the changes in the fair value of our investment within net income. The impact on our consolidated financial statements and disclosures will depend on the amount of accumulated unrealized holding gains and losses recognized in other comprehensive income at December 31, 2017, and changes in the fair value of our investment in Cenovus Energy subsequent to that date. For additional information on our investment in Cenovus Energy, see Note 6 Investment in Cenovus Energy, Note 14 Fair Value Measurement, and Note 15 Accumulated Other Comprehensive Income (Loss).

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In February 2016, the FASB issued ASU No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, Leases, and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. We plan to adopt ASU No. 2016-02 effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures.

In June 2016, the FASB issued ASU No. 2016-13, Measurement of Credit Losses on Financial Instruments (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

Supplementary Information Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and/or ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips results on a consolidated basis.

In May 2017, ConocoPhillips Company received a $9.8 billion return of capital from a nonguarantor subsidiary to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In September 2017, ConocoPhillips received a $5.0 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

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	Millions of Dollars					
	Three Months Ended September 30, 2017					
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$	2,997		3,691		6,688
Equity in earnings (losses) of affiliates	486	348		119	(757)	196
Gain on dispositions		879		(633)		246
Other income		12		53		65
Intercompany revenues	10	77	43	774	(904)	
Total Revenues and Other Income	496	4,313	43	4,004	(1,661)	7,195
Costs and Expenses						
Purchased commodities		2,666		1,001	(741)	2,926
Production and operating expenses		221		1,004	(1)	1,224
Selling, general and administrative expenses	2	119		11		132
Exploration expenses		30		45		75
Depreciation, depletion and amortization		203		1,405		1,608
Impairments		1		5		6
Taxes other than income taxes		29		146		175
Accretion on discounted liabilities		8		81		89
Interest and debt expense	86	169	37	121	(162)	251
Foreign currency transaction (gains) losses	(27)	1	77	(46)		5
Other expenses	50	1				51
Total Costs and Expenses	111	3,448	114	3,773	(904)	6,542
Income (Loss) before income taxes	385	865	(71)	231	(757)	653
Income tax provision (benefit)	(35)	379	6	(133)		217
Net income (loss)	420	486	(77)	364	(757)	436
Less: net income attributable to noncontrolling interests				(16)		(16)
Net Income (Loss) Attributable to ConocoPhillips	$ 420	486	(77)	348	(757)	420
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 1,470	1,536	22	864	(2,422)	1,470

Income Statement	Three Months Ended September 30, 2016					
Revenues and Other Income						
Sales and other operating revenues	$	2,933		3,482		6,415
Equity in losses of affiliates	(958)	(397)		(26)	1,321	(60)
Gain on dispositions		11		40		51
Other income	1	3		106		110
Intercompany revenues	18	71	60	793	(942)	
Total Revenues and Other Income	(939)	2,621	60	4,395	379	6,516
Costs and Expenses						
Purchased commodities		2,563		1,024	(768)	2,819
Production and operating expenses		324		1,207	(5)	1,526
Selling, general and administrative expenses	2	158		43		203
Exploration expenses		192		265		457
Depreciation, depletion and amortization		351		2,074		2,425

Impairments				123		123
Taxes other than income taxes		26		135		161
Accretion on discounted liabilities		11		97		108
Interest and debt expense	135	159	56	154	(169)	335
Foreign currency transaction (gains) losses	8		(26)	31		13
Total Costs and Expenses	145	3,784	30	5,153	(942)	8,170
Income (Loss) before income taxes	(1,084)	(1,163)	30	(758)	1,321	(1,654)
Income tax benefit	(44)	(205)	(4)	(375)		(628)
Net income (loss)	(1,040)	(958)	34	(383)	1,321	(1,026)
Less: net income attributable to noncontrolling interests				(14)		(14)
Net Income (Loss) Attributable to ConocoPhillips	$ (1,040)	(958)	34	(397)	1,321	(1,040)
Comprehensive Loss Attributable to ConocoPhillips	$ (1,113)	(1,031)	(10)	(460)	1,501	(1,113)

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	Millions of Dollars					
	Nine Months Ended September 30, 2017					
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$	9,066		11,921		20,987
Equity in earnings (losses) of affiliates	(2,092)	(776)		432	3,010	574
Gain on dispositions		908		1,236		2,144
Other income	1	27		115		143
Intercompany revenues	39	222	126	2,360	(2,747)	
Total Revenues and Other Income	(2,052)	9,447	126	16,064	263	23,848
Costs and Expenses						
Purchased commodities		8,068		3,229	(2,257)	9,040
Production and operating expenses		501		3,351	(3)	3,849
Selling, general and administrative expenses	8	365		55	(5)	423
Exploration expenses		435		289		724
Depreciation, depletion and amortization		658		4,554		5,212
Impairments		1,075		5,400		6,475
Taxes other than income taxes		114		490		604
Accretion on discounted liabilities		28		248		276
Interest and debt expense	340	505	110	399	(482)	872
Foreign currency transaction (gains) losses	(49)	3	145	(71)		28
Other expense	267	18				285
Total Costs and Expenses	566	11,770	255	17,944	(2,747)	27,788
Loss before income taxes	(2,618)	(2,323)	(129)	(1,880)	3,010	(3,940)
Income tax provision (benefit)	(184)	(231)	12	(1,146)		(1,549)
Net loss	(2,434)	(2,092)	(141)	(734)	3,010	(2,391)
Less: net income attributable to noncontrolling interests				(43)		(43)
Net Loss Attributable to ConocoPhillips	$ (2,434)	(2,092)	(141)	(777)	3,010	(2,434)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ (1,533)	(1,191)	39	(37)	1,189	(1,533)

Income Statement	Nine Months Ended September 30, 2016					
Revenues and Other Income						
Sales and other operating revenues	$	7,289		9,595		16,884
Equity in earnings of affiliates	(3,388)	(1,168)		(325)	4,752	(129)
Gain on dispositions		96		106		202
Other income (loss)	1	(2)		150		149
Intercompany revenues	62	220	176	2,246	(2,704)	
Total Revenues and Other Income	(3,325)	6,435	176	11,772	2,048	17,106
Costs and Expenses						
Purchased commodities		6,409		2,585	(1,948)	7,046
Production and operating expenses		1,065		3,502	(242)	4,325
Selling, general and administrative expenses	7	448		107	(6)	556
Exploration expenses		1,174		398		1,572
Depreciation, depletion and amortization		914		6,087		7,001

Impairments		41		280		321
Taxes other than income taxes		122		416		538
Accretion on discounted liabilities		35		294		329
Interest and debt expense	385	457	168	426	(508)	928
Foreign currency transaction (gains) losses	(34)	2	207	(163)		12
Total Costs and Expenses	358	10,667	375	13,932	(2,704)	22,628
Loss before income taxes	(3,683)	(4,232)	(199)	(2,160)	4,752	(5,522)
Income tax provision (benefit)	(103)	(844)	(3)	(1,032)		(1,982)
Net loss	(3,580)	(3,388)	(196)	(1,128)	4,752	(3,540)
Less: net income attributable to noncontrolling interests				(40)		(40)
Net Loss Attributable to ConocoPhillips	$ (3,580)	(3,388)	(196)	(1,168)	4,752	(3,580)
Comprehensive Loss Attributable to ConocoPhillips	$ (2,777)	(2,585)	(6)	(230)	2,821	(2,777)

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	Millions of Dollars September 30, 2017					
Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$	226	35	6,650		6,911
Short-term investments				2,696		2,696
Accounts and notes receivable	19	1,738	35	3,952	(2,380)	3,364
Investment in Cenovus Energy		2,084				2,084
Inventories		138		885		1,023
Prepaid expenses and other current assets	1	128	6	771	(30)	876
Total Current Assets	20	4,314	76	14,954	(2,410)	16,954
Investments, loans and long-term receivables*	31,001	52,867	2,493	18,571	(94,775)	10,157
Net properties, plants and equipment		4,391		42,759	(481)	46,669
Other assets	34	2,140	188	1,288	(2,569)	1,081
Total Assets	$ 31,055	63,712	2,757	77,572	(100,235)	74,861
Liabilities and Stockholders Equity						
Accounts payable	$	2,480	2	3,314	(2,380)	3,416
Short-term debt	(5)	1,263	7	78	(12)	1,331
Accrued income and other taxes		107		898		1,005
Employee benefit obligations		379		149		528
Other accruals	57	255	55	514	(30)	851
Total Current Liabilities	52	4,484	64	4,953	(2,422)	7,131
Long-term debt	3,785	11,816	1,705	2,845	(478)	19,673
Asset retirement obligations and accrued environmental costs		490		7,273		7,763
Deferred income taxes				8,267	(2,005)	6,262
Employee benefit obligations		1,278		625		1,903
Other liabilities and deferred credits*	3,280	8,769	893	14,962	(26,487)	1,417
Total Liabilities	7,117	26,837	2,662	38,925	(31,392)	44,149
Retained earnings	21,607	11,914	(682)	9,193	(13,902)	28,130
Other common stockholders equity	2,331	24,961	777	29,242	(54,941)	2,370
Noncontrolling interests				212		212
Total Liabilities and Stockholders Equity	$ 31,055	63,712	2,757	77,572	(100,235)	74,861

**Includes intercompany loans.*

Balance Sheet	December 31, 2016					
Assets						
Cash and cash equivalents	$	358	13	3,239		3,610
Short-term investments				50		50
Accounts and notes receivable	22	1,968	23	6,103	(4,702)	3,414
Inventories		84		934		1,018
Prepaid expenses and other current assets	2	116	8	415	(24)	517
Total Current Assets	24	2,526	44	10,741	(4,726)	8,609
Investments, loans and long-term receivables*	37,901	64,434	2,296	31,643	(114,602)	21,672
Net properties, plants and equipment		6,301		52,030		58,331
Other assets	40	2,194	220	1,240	(2,534)	1,160
Total Assets	$ 37,965	75,455	2,560	95,654	(121,862)	89,772

Liabilities and Stockholders Equity						
Accounts payable	$	4,683	1	3,671	(4,702)	3,653
Short-term debt	(10)	999	6	94		1,089
Accrued income and other taxes		85		399		484
Employee benefit obligations		489		200		689
Other accruals	171	271	40	536	(24)	994
Total Current Liabilities	161	6,527	47	4,900	(4,726)	6,909
Long-term debt	8,975	12,635	1,710	2,866		26,186
Asset retirement obligations and accrued environmental costs		925		7,500		8,425
Deferred income taxes				10,972	(2,023)	8,949
Employee benefit obligations		1,901		651		2,552
Other liabilities and deferred credits*	417	10,391	748	17,832	(27,863)	1,525
Total Liabilities	9,553	32,379	2,505	44,721	(34,612)	54,546
Retained earnings	25,025	14,015	(541)	12,883	(19,834)	31,548
Other common stockholders equity	3,387	29,061	596	37,798	(67,416)	3,426
Noncontrolling interests				252		252
Total Liabilities and Stockholders Equity	$ 37,965	75,455	2,560	95,654	(121,862)	89,772

**Includes intercompany loans.*

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			Millions of Dollars Nine Months Ended September 30, 2017			
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (161)	634	22	6,868	(2,767)	4,596
Cash Flows From Investing Activities						
Capital expenditures and investments		(1,230)		(2,711)	867	(3,074)
Working capital changes associated with investing activities		36		(54)		(18)
Proceeds from asset dispositions	5,000	10,974		12,737	(14,971)	13,740
Purchases of short-term investments				(2,583)		(2,583)
Long-term advances/loans related parties		(74)		(20)	94	
Collection of advances/loans related parties	658	127		2,196	(2,866)	115
Intercompany cash management	2,903	(2,474)		(429)		
Other				51		51
Net Cash Provided by Investing Activities	8,561	7,359		9,187	(16,876)	8,231
Cash Flows From Financing Activities						
Issuance of debt		20		74	(94)	
Repayment of debt	(5,459)	(3,146)		(855)	2,866	(6,594)
Issuance of company common stock	87				(152)	(65)
Repurchase of company common stock	(2,045)					(2,045)
Dividends paid	(986)			(2,919)	2,919	(986)
Other	3	(5,000)		(9,187)	14,104	(80)
Net Cash Used in Financing Activities	(8,400)	(8,126)		(12,887)	19,643	(9,770)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		1		243		244
Net Change in Cash and Cash Equivalents		(132)	22	3,411		3,301
Cash and cash equivalents at beginning of period		358	13	3,239		3,610
Cash and Cash Equivalents at End of Period	$	226	35	6,650		6,911

Statement of Cash Flows			Nine Months Ended September 30, 2016			
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	$ (315)	(124)	(4)	4,307	(904)	2,960
Cash Flows From Investing Activities						
Capital expenditures and investments		(889)		(3,382)	401	(3,870)
Working capital changes associated with investing activities		(135)		(266)		(401)
Proceeds from asset dispositions	2,300	175		275	(2,331)	419
Purchases of short-term investments				(229)		(229)
Long-term advances/loans related parties		(803)			803	
Collection of advances/loans related parties		60		1,072	(1,024)	108
Intercompany cash management	(2,767)	2,272		495		
Other		3		58		61
Net Cash Provided by (Used in) Investing Activities	(467)	683		(1,977)	(2,151)	(3,912)

Cash Flows From Financing Activities						
Issuance of debt	1,600	2,994		803	(803)	4,594
Repayment of debt		(964)		(899)	1,024	(839)
Issuance of company common stock	122				(174)	(52)
Dividends paid	(940)			(1,078)	1,078	(940)
Other		(2,318)		295	1,930	(93)
Net Cash Provided by (Used in) Financing Activities	782	(288)		(879)	3,055	2,670
Effect of Exchange Rate Changes on Cash and Cash Equivalents				4		4
Net Change in Cash and Cash Equivalents		271	(4)	1,455		1,722
Cash and cash equivalents at beginning of period		4	15	2,349		2,368
Cash and Cash Equivalents at End of Period	$	275	11	3,804		4,090

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Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis is the company s analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes. It contains forward-looking statements including, without limitation, statements relating to the company s plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, target and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 57.

The terms earnings and loss as used in Management s Discussion and Analysis refer to net income (loss) attributable to ConocoPhillips.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Our diverse portfolio primarily includes resource-rich North American unconventional assets and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, we had operations and activities in 17 countries, approximately 11,600 employees worldwide and total assets of $75 billion as of September 30, 2017.

Overview

The energy landscape continues to be challenged as global production oversupply has caused ongoing weakness in commodity prices.

In the fourth quarter of 2016, given our view that commodity prices were likely to remain lower and more volatile, we announced an updated value proposition. Our value proposition principles, which are to maintain a strong investment grade balance sheet, grow our dividend and pursue disciplined growth, remained essentially unchanged; however, we took steps to improve our competitiveness and resilience by establishing clear priorities for allocating future cash flows. In order, these priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares; and invest capital to grow absolute production. In conjunction with updating our value proposition, we outlined a 2017 to 2019 operating plan that achieves our cash allocation priorities at Brent prices at or above $50 per barrel with asset sales of $5 billion to $8 billion.

Through the first three quarters of 2017, we took significant actions that allowed us to make substantial progress on some of our stated priorities. We have considerably accelerated these priorities with plans to reduce debt to less than $20 billion and triple our annual planned share buybacks from $1 billion to $3 billion, both in 2017. On a longer-term basis, we have adjusted our targeted debt level to $15 billion and aim to repurchase up to $6 billion of our common stock by year-end 2019. Through the third quarter, we have increased our quarterly dividend by 6 percent to $0.265 per share, made repayments totaling $6.6 billion on our debt, repurchased 45 million shares of our common stock totaling $2 billion and continued the disposition of noncore assets in our portfolio.

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Total consideration for the transaction was $11 billion in cash after customary adjustments, 208 million Cenovus Energy shares, and a five-year uncapped contingent payment. The contingent payment, calculated and paid on a quarterly basis, is $6 million Canadian dollars (CAD) for every $1 CAD by which the Western Canada Select (WCS) quarterly average crude price exceeds $52 CAD per barrel. Proceeds from this transaction are being directed to our stated cash priorities.

On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and a contingent payment of up to $300 million. The six-year contingent payment is effective beginning January 1, 2018, and is due annually for periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units (MMBTU). Proceeds from this transaction are being used for general corporate purposes.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments. Proceeds from this transaction are being used for general corporate purposes.

On June 28, 2017, we signed a definitive agreement to sell our interests in the Barnett for $305 million subject to net customary adjustments. Proceeds from this transaction will be used for general corporate purposes.

For additional information on our dispositions, see Note 4 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Our asset dispositions are in line with our strategy, announced in November 2016, to focus on low cost-of-supply projects in our portfolio that strategically fit our development plans. We are focused on delivering on our value proposition, and are aggressively executing on our stated plans, which we believe position the company for success in the current environment of price uncertainty and ongoing volatility.

Operationally, we continue to focus on safely executing our capital program and remaining attentive to our costs. Production excluding Libya was 1,202 thousand barrels of oil equivalent per day (MBOED) in the third quarter of 2017. Our underlying production, which excludes Libya and the third-quarter impact of closed and signed dispositions of 58 MBOED in 2017 and 429 MBOED in 2016, increased 1.4 percent compared with the same period of 2016. Underlying production on a per debt-adjusted share basis grew by 19 percent compared to the third quarter of 2016. Production per debt-adjusted share is calculated on an underlying production basis using ending period debt divided by ending share price plus ending shares outstanding. We believe production per debt-adjusted share is useful to investors as it provides a consistent view of production on a total equity basis by converting debt to equity and allows for comparisons across peer companies. We continue to pursue sustainable operating cost reductions within our business. Operating costs include production and operating expense; selling, general and administrative expense; and exploration general and administrative, geological and geophysical, lease rental and other expense.

Business Environment

Global oil market conditions remain challenged. Global market fundamentals are trending toward a better balance; however, it will take time for the high level of global inventories to drop to more normal levels.

Global oil prices experienced elevated levels of volatility throughout 2016 with first quarter Brent crude oil prices reaching a 10-year quarterly average low of $33.89 per barrel. Global oil prices began to improve at the end of 2016 and have continued trending upward in response to stronger global demand and slower production growth.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Among other dynamics that could influence world energy markets and commodity prices are global economic health, supply disruptions or fears thereof caused

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by civil unrest or military conflicts, actions taken by Organization of Petroleum Exporting Countries (OPEC), environmental laws, tax regulations, governmental policies and weather-related disruptions. North America s energy landscape has been transformed from resource scarcity to an abundance of supply, primarily due to advances in technology responsible for the rapid growth of tight oil production, successful exploration and rising production from the Canadian oil sands. Our strategy is to create value through price cycles by delivering on the financial and operational priorities that underpin our value proposition.

Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas, the prices of which are subject to factors external to the company and over which we have no control. The following graph depicts the trend in average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and Henry Hub natural gas:

Brent crude oil prices averaged $52.09 per barrel in the third quarter of 2017, an increase of 14 percent compared with $45.85 per barrel in the third quarter of 2016, and an increase of 5 percent compared with $49.83 per barrel in the second quarter of 2017. Industry crude prices for WTI averaged $48.16 per barrel in the third quarter of 2017, an increase of 7 percent compared with $44.88 per barrel in the third quarter of 2016. WTI prices remained essentially flat with the second quarter of 2017 reflecting inventory builds from permitting and outages from Hurricane Harvey.

Henry Hub natural gas prices averaged $2.99 per MMBTU in the third quarter of 2017, an increase of 6 percent compared with $2.81 per MMBTU in the third quarter of 2016, and a decrease of 6 percent compared with $3.19 per MMBTU in the second quarter of 2017. Prices improved relative to the same period of 2016 as a result of lower U.S. inventories and increased exports, but declined from the prior quarter as natural gas production increased in the contiguous United States.

Our realized bitumen price increased from $17.82 per barrel in the third quarter of 2016 and $22.42 per barrel in the second quarter of 2017, to $24.19 per barrel in the third quarter of 2017. The change, compared to both periods, was primarily due to improvement in the WCS benchmark price and changes in costs per barrel resulting from the disposition of our interest in the FCCL Partnership.

Our total average realized price was $39.49 per barrel of oil equivalent (BOE) in the third quarter of 2017, an increase of 33 percent compared with $29.78 per BOE in the third quarter of 2016, reflecting increased average realized prices for all commodities.

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Key Operating and Financial Summary

Significant items during the third quarter of 2017 included the following:

- Achieved third-quarter production excluding Libya of 1,202 MBOED; 1.4 percent year-over-year underlying production growth excluding the impact of closed or signed dispositions; underlying production grew 19 percent on a production per debt-adjusted share basis.
- Lowering full-year 2017 expected capital expenditures to $4.5 billion, a 10 percent reduction from initial guidance.
- Maintaining full-year production guidance despite impacts from Hurricane Harvey, which were offset by increased volumes from our globally diverse portfolio.
- Cash provided by operating activities has exceeded capital and dividends year-to-date.
- Reduced year-over-year production and operating expenses by 20 percent.
- Closed San Juan Basin and Panhandle dispositions. Expect over $16 billion of dispositions during 2017.
- Repurchased $1.0 billion in shares, which reduced ending share count by 2 percent from the end of the second quarter. On track for $3 billion in share repurchases in 2017.
- Reduced balance sheet debt by $2.4 billion and received credit rating upgrade. On track for less than $20 billion of debt by year-end.
- Released final project financing loan guarantee for APLNG in Australia after successful two-train lenders test.

Outlook

Capital and Production Guidance

Fourth-quarter and full-year 2017 production is expected to be 1,195 to 1,235 MBOED and 1,350 to 1,360 MBOED, respectively. This excludes Libya and reflects expected impacts from the Barnett disposition, which is anticipated to close in the fourth quarter of 2017.

Full-year guidance for capital expenditures has been lowered to $4.5 billion.

We expect to reduce debt to less than $20 billion by year-end 2017, and expect full-year share repurchases of $3 billion.

Marketing Activities

In line with our strategic objectives, we are currently marketing certain noncore assets. On July 31, 2017, we completed the sale of our interests in the San Juan Basin. On September 29, 2017, we completed the sale of our interest in the Panhandle assets. On June 28, 2017, we signed a definitive agreement to sell our interests in the Barnett for $305 million subject to net customary adjustments. Given the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets, on May 17, 2017, we adjusted our outlook on total consideration from asset dispositions from the previously stated range of $5 billion to $8 billion over the next two years, to more than $16 billion in 2017.

Impairments

As we continue to market certain noncore assets, it is possible we will incur future impairment charges. While we may incur additional future impairment charges to long-lived assets, it is not reasonably practicable to quantify their financial impacts. These impacts could be material to our results of operations for the periods in which they are incurred.

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RESULTS OF OPERATIONS

Unless otherwise indicated, discussion of results for the three- and nine-month periods ended September 30, 2017, is based on a comparison with the corresponding periods of 2016.

Consolidated Results

A summary of the company s net income (loss) attributable to ConocoPhillips by business segment follows:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Alaska	$ **103**	59	**291**	204
Lower 48	**(97)**	(491)	**(2,995)**	(2,082)
Canada	**280**	(314)	**2,607**	(783)
Europe and North Africa	**85**	163	**379**	132
Asia Pacific and Middle East	**396**	(87)	**(1,540)**	(20)
Other International	**(20)**	(47)	**(77)**	(100)
Corporate and Other	**(327)**	(323)	**(1,099)**	(931)
Net income (loss) attributable to ConocoPhillips	$ **420**	(1,040)	**(2,434)**	(3,580)

Net income (loss) attributable to ConocoPhillips increased $1,460 million in the third quarter and $1,146 million in the nine-month period of 2017, mainly due to:

- A $1.6 billion after-tax gain on the sale of certain Canadian assets, $190 million of which was recognized in the third quarter of 2017 in relation to environmental claims.
- Higher realized commodity prices.
- Lower depreciation, depletion and amortization (DD&A) expense, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts.
- Recognition of deferred tax benefits totaling $996 million in the first quarter of 2017, primarily related to the disposition of certain Canadian assets.
- Improved equity earnings, mainly due to higher realized prices, the absence of a third-quarter 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to the U.S. dollar, and lower DD&A from asset disposition impacts. These increases were partly offset by lower volumes from the disposition of our interest in the FCCL Partnership.
- Lower exploration expenses mainly due to reduced leasehold impairment expense, dry hole costs and other exploration expenses.
- Lower production and operating expenses, primarily due to asset disposition impacts.
- A $114 million tax benefit in the third quarter of 2017 related to our prior decision to exit Nova Scotia deepwater exploration.

The increases in net income were partly offset by:

- Higher proved property and equity investment impairments, including a combined $2.5 billion after-tax impairment related to the announced sales of our interests in the San Juan Basin and the Barnett, and a $2.4 billion before- and after-tax impairment of our equity investment in APLNG, all in the second quarter of 2017.
- Lower volumes primarily due to asset dispositions in our Lower 48 and Canada segments and normal field decline.

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A $225 million after-tax charge associated with our early retirement of debt in 2017, $41 million of which was recognized in the third quarter of 2017.

The absence of a $138 million net deferred tax benefit in the third quarter of 2016, resulting from a change in the U.K. tax rate.

See the Segment Results section for additional information.

Income Statement Analysis

Sales and other operating revenues increased 24 percent in the nine-month period of 2017 mainly due to higher realized prices across all commodities, partly offset by lower sales volumes, primarily in our Lower 48 and Canada segments.

Equity in earnings (losses) of affiliates increased $256 million in the third quarter and $703 million in the nine-month period of 2017. The increase in equity earnings in the third quarter was primarily due to the absence of a 2016 deferred tax charge of $174 million resulting from a tax functional currency change; higher realized commodity prices at APLNG and Qatar Liquefied Gas Company Limited (3) (QG3); reduced DD&A driven by the disposition of our interest in the FCCL Partnership; and increased volumes at APLNG given the ramp-up of Trains 1 and 2. The increase in earnings was partly offset by lower volumes as a result of our FCCL disposition.

In the nine-month period, equity in earnings of affiliates was further improved due to higher bitumen prices at FCCL prior to the disposition.

Gain on dispositions increased $195 million in the third quarter and $1,942 million in the nine-month period of 2017. The increase in the three- and nine-month periods of 2017 was primarily due to before-tax gains of $1.9 billion and $281 million in the second and third quarters of 2017, respectively, on the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets.

Purchased commodities increased 28 percent in the nine-month period of 2017, largely due to higher natural gas prices.

Production and operating expenses decreased 20 percent in the third quarter and 11 percent in the nine-month period of 2017, primarily due to disposition impacts and lower costs and activity across segments.

SG&A expenses decreased 24 percent in the nine-month period of 2017, primarily due to lower restructuring costs and pension settlement expenses.

Exploration expenses decreased 84 percent in the third quarter primarily due to reduced other exploration expenses and dry hole costs. In addition to these factors, exploration expenses decreased 54 percent in the nine-month period of 2017 due to reduced leasehold impairment expense.

Other exploration expenses were reduced mainly due to the absence of a $134 million expense in the third quarter of 2016 related to the cancellation of our final Gulf of Mexico deepwater drillship contract.

Dry hole costs were reduced primarily due to the absence of before-tax charges in deepwater Gulf of Mexico of $249 million mainly in the second quarter of 2016 for our Gibson and Tiber wells, and $128 million in the six-month period of 2016 for our Melmar well. The absence of a $164 million charge in the third quarter of 2016 for a dry hole in Nova Scotia also reduced costs in the three- and nine-month periods. The reduction in dry hole costs was partly offset by before-tax charges totaling $291 million in the first quarter of 2017 for multiple wells in Shenandoah, including wells previously suspended.

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Leasehold impairment expense was reduced mainly due to the absence of 2016 before-tax charges of $203 million in the second quarter for our Gibson and Tiber leaseholds. The expense was further reduced by the absence of before-tax charges, primarily in the first quarter, of $95 million for our Melmar leasehold and $79 million for various Gulf of Mexico leases after completion of an initial marketing effort. The reduction was partly offset by a before-tax charge of $51 million in the first quarter of 2017 for Shenandoah in deepwater Gulf of Mexico.

For additional information on other exploration expenses, dry hole costs and leasehold impairments, see Note 7 Suspended Wells and Other Exploration Expenses and Note 8 Impairments, in the Notes to Consolidated Financial Statements.

DD&A decreased 34 percent in the third quarter and 26 percent in the nine-month period of 2017, mainly due to lower unit-of-production rates from reserve revisions and disposition impacts in our Canada and Lower 48 segments.

Impairments decreased $117 million in the third quarter and increased $6.2 billion in the nine-month period of 2017. For additional information, see Note 8 Impairments, in the Notes to Consolidated Financial Statements.

Other expense included before-tax charges of $234 million and $51 million in the second and third quarters of 2017, respectively, for premiums on early debt retirements.

See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

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Summary Operating Statistics

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Average Net Production				
Crude oil (MBD)*	**582**	586	**591**	598
Natural gas liquids (MBD)	**95**	148	**119**	146
Bitumen (MBD)	**63**	193	**140**	173
Natural gas (MMCFD)**	**2,918**	3,777	**3,405**	3,855
Total Production (MBOED)***	**1,226**	1,557	**1,418**	1,560
	Dollars Per Unit			
Average Sales Prices				
Crude oil (per barrel)	**$ 49.39**	43.21	**49.51**	38.97
Natural gas liquids (per barrel)	**23.82**	16.18	**23.25**	15.04
Bitumen (per barrel)	**24.19**	17.82	**22.25**	12.65
Natural gas (per thousand cubic feet)	**4.11**	3.05	**3.91**	2.85
	Millions of Dollars			
Exploration Expenses				
General administrative, geological and geophysical, lease rental, and other	**$ 68**	270	**289**	562
Leasehold impairment	**10**	24	**81**	418
Dry holes	**(3)**	163	**354**	592
	$ 75	457	**724**	1,572

**Thousands of barrels per day.*

***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*

****Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At September 30, 2017, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production from operations decreased 21 percent in the third quarter and 9 percent in the nine-month period of 2017. The decrease in total average production in both periods, primarily resulted from noncore asset dispositions, including our Canada and San Juan transactions which were completed in the second and third quarters of 2017, respectively, and normal field decline. The decrease in production was partly offset by production from major developments, including tight oil plays in the Lower 48; Malikai and the Kebabangan gas field in Malaysia; Surmont 2 in Canada; and APLNG in Australia. Improved drilling and well performance in Alaska, Norway and China; as well as the resumption and ramp-up of production from Libya, also partly offset the decrease in production in both periods. In the third quarter of 2017, we achieved production of 1,226 MBOED. Excluding Libya, third-quarter production was 1,202 MBOED. Adjusted for the third-quarter impact of closed and signed dispositions of 58 MBOED in 2017 and 429 MBOED in 2016, our underlying production increased 16 MBOED, or 1.4 percent, compared with the third quarter of 2016.

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as most of our western Canada gas assets to Cenovus Energy. Production associated with these assets was 260 MBOED in the third quarter of 2016, and 138 MBOED and 257 MBOED in the nine-month periods of 2017 and 2016, respectively.

On July 31, 2017, we completed the sale of our interests in the San Juan Basin, which produced 40 MBOED and 123 MBOED in the third quarters of 2017 and 2016, respectively, and 90 MBOED and 124 MBOED in the corresponding nine-month periods.

On September 29, 2017, we completed the sale of our interest in the Panhandle assets, which produced 8 MBOED and 6 MBOED in the third quarters of 2017 and 2016, respectively, and 8 MBOED and 7 MBOED in the corresponding nine-month periods.

On June 28, 2017, we signed a definitive agreement to sell our interests in the Barnett, which produced 10 MBOED and 11 MBOED in the third quarters and nine-month periods of 2017 and 2016, respectively. The transaction is subject to specific conditions precedent being satisfied, including regulatory approval, and is expected to close in the fourth quarter of 2017.

Year-end 2016 reserves associated with our Canadian transaction and the disposition of our interests in the San Juan Basin were 1.3 billion barrels of oil equivalent (BBOE) and 0.6 BBOE, respectively.

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Segment Results

Alaska

		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**103**	59	**291**	204
Average Net Production					
Crude oil (MBD)		**154**	148	**166**	160
Natural gas liquids (MBD)		**11**	11	**14**	12
Natural gas (MMCFD)		**5**	18	**7**	28
Total Production (MBOED)		**166**	162	**181**	177
Average Sales Prices					
Crude oil (dollars per barrel)	$	**50.53**	43.43	**50.81**	39.69
Natural gas (dollars per thousand cubic feet)		**4.55**	6.95	**2.77**	5.20

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids and natural gas. As of September 30, 2017, Alaska contributed 21 percent of our worldwide liquids production and less than 1 percent of our worldwide natural gas production.

Earnings from Alaska increased 75 percent in the third quarter and 43 percent in the nine-month period of 2017. The increase in earnings in the third quarter was primarily due to higher crude oil realized prices and lower DD&A expense from reserve revisions. The earnings improvement was partly offset by adverse tax impacts including adjustments to our worldwide tax apportionment and enhanced oil recovery tax credits.

In addition to the items discussed above, earnings increased in the nine-month period of 2017 due to lower production and operating expenses from reduced activity. The earnings increase in the nine-month period was partly offset by a $110 million after-tax impairment charge for the associated properties, plants and equipment carrying value of our small interest in a nonoperated producing property; the absence of a $57 million after-tax benefit in 2016 for the recognition of state deferred tax assets; and higher exploration expense from increased seismic activity in the Western North Slope and higher dry hole costs.

Average production increased 2 percent in the third quarter and the nine-month period of 2017, as the impact of normal field decline was more than offset by well performance in the Western North Slope, Greater Prudhoe and Greater Kuparuk areas and lower downtime.

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Lower 48

		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Loss Attributable to ConocoPhillips (millions of dollars)	$	**(97)**	(491)	**(2,995)**	(2,082)
Average Net Production					
Crude oil (MBD)		**175**	195	**176**	201
Natural gas liquids (MBD)		**64**	92	**73**	89
Natural gas (MMCFD)		**765**	1,224	**1,007**	1,228
Total Production (MBOED)		**366**	491	**417**	495
Average Sales Prices					
Crude oil (dollars per barrel)	$	**45.29**	40.09	**44.84**	35.54
Natural gas liquids (dollars per barrel)		**20.72**	14.57	**20.55**	12.93
Natural gas (dollars per thousand cubic feet)		**2.63**	2.59	**2.74**	2.03

The Lower 48 segment consists of operations located in the U.S. Lower 48 states, as well as producing properties and exploration activities in the Gulf of Mexico. As of September 30, 2017, the Lower 48 contributed 30 percent of our worldwide liquids production and 30 percent of our worldwide natural gas production.

Losses from Lower 48 decreased 80 percent in the third quarter primarily due to lower DD&A expense, mainly resulting from a lower unit-of-production rate from reserve revisions, disposition impacts and lower volumes; lower exploration expenses mainly resulting from the absence of $87 million after-tax in rig cancellation and related third-party costs for our final Gulf of Mexico deepwater drillship contract; and higher realized crude oil, natural gas liquids and natural gas prices. The earnings improvement in the third quarter was partly offset by lower volumes from normal field decline and asset dispositions.

Losses from Lower 48 increased 44 percent in the nine-month period of 2017. The factors discussed above, along with the absence of 2016 after-tax dry hole costs and leasehold impairment charges totaling $439 million related to our Gibson, Tiber and Melmar wells and leases and lower production and operating expenses, were more than offset by 2017 proved property impairments totaling $2.5 billion after-tax for our interests in the San Juan Basin and the Barnett.

In the third quarter of 2017, our average realized crude oil price of $45.29 per barrel was 6 percent less than WTI of $48.16 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast and Bakken, and may widen in the near term.

Total average production decreased 25 percent in the third quarter and 16 percent in the nine-month period of 2017. The decrease was mainly attributable to normal field decline, the disposition of our interests in the San Juan Basin and Hurricane Harvey impacts to our Eagle Ford operations in the third quarter, partly offset by new production, primarily from Eagle Ford, Bakken and the Permian Basin.

Asset Disposition Update

On July 31, 2017, we completed the sale of our interests in the San Juan Basin for total proceeds comprised of $2.5 billion in cash after customary adjustments and a contingent payment of up to $300 million. The six-year contingent payment is effective beginning January 1, 2018, and is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per million British thermal units.

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On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

On June 28, 2017, we signed a definitive agreement with an affiliate of Miller Thomson & Partners LLC to sell our interests in the Barnett for $305 million in cash, subject to customary adjustments. The transaction is subject to specific conditions precedent being satisfied, including regulatory approval, and is expected to close in the fourth quarter of 2017.

See Note 4 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements, for additional information regarding our asset dispositions.

Canada

		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$	**280**	(314)	**2,607**	(783)
Average Net Production					
Crude oil (MBD)		**1**	7	**3**	8
Natural gas liquids (MBD)		**1**	23	**12**	23
Bitumen (MBD)					
Consolidated operations		**63**	41	**56**	29
Equity affiliates			152	**84**	144
Total bitumen		**63**	193	**140**	173
Natural gas (MMCFD)		**10**	517	**246**	538
Total Production (MBOED)		**67**	309	**196**	294
Average Sales Prices					
Crude oil (dollars per barrel)	$		37.50	**43.46**	33.47
Natural gas liquids (dollars per barrel)			14.99	**21.44**	13.41
Bitumen (dollars per barrel)					
Consolidated operations		**24.19**	15.73	**19.93**	11.36
Equity affiliates			18.39	**23.83**	12.91
Total bitumen		**24.19**	17.82	**22.25**	12.65
Natural gas (dollars per thousand cubic feet)			1.71	**1.95**	1.28

Our Canadian operations mainly consist of an oil sands development in the Athabasca Region of northeastern Alberta and a liquids-rich unconventional play in western Canada. As of September 30, 2017, Canada contributed 18 percent of our worldwide liquids production and 7 percent of our worldwide natural gas production.

Earnings from Canada increased by $594 million in the third quarter and $3,390 million in the nine-month period of 2017. Earnings increased in the third quarter primarily due to an additional after-tax gain of $190 million for funds received in relation to environmental claims from our Canada disposition, discussed below, and lower DD&A mainly due to disposition impacts. Additionally, reduced exploration expenses including the absence of 2016 dry hole costs for the Cheshire well in Nova Scotia; a $114 million tax benefit

related to our prior decision to exit Nova Scotia deepwater exploration; and lower production and operating expenses, further improved earnings. The third-quarter earnings increase was partly offset by lower equity earnings from the disposition of our nonoperated interest in the FCCL Partnership.

In the nine-month period of 2017, earnings increased mainly due to an after-tax gain of $1.6 billion, primarily recognized in the second quarter, on the sale of certain Canadian assets, further discussed below. The first-quarter 2017 recognition of $996 million in deferred tax benefits related to the capital gains component of our disposition and the recognition of previously unrealizable Canadian tax basis also increased earnings in the nine-month period. Additionally, higher realized prices across all commodities and lower volumes from the disposition of our western Canada gas assets impacted earnings in both periods.

Total average production decreased 78 percent in the third quarter and 33 percent in the nine-month period of 2017. The production decrease in both periods was primarily due to the Canada disposition, partly offset by production ramp-up at Surmont.

Asset Disposition Update

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. See Note 4 Assets Held for Sale or Sold and Note 6 Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements, for additional information regarding our Canada disposition.

Europe and North Africa

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Net Income Attributable to ConocoPhillips (millions of dollars)	$ **85**	163	**379**	132
Average Net Production				
Crude oil (MBD)	**141**	121	**139**	117
Natural gas liquids (MBD)	**7**	6	**8**	6
Natural gas (MMCFD)	**408**	358	**475**	441
Total Production (MBOED)	**216**	187	**227**	196
Average Sales Prices				
Crude oil (dollars per barrel)	$ **51.05**	46.59	**51.90**	42.39
Natural gas liquids (dollars per barrel)	**31.16**	21.38	**29.69**	20.86
Natural gas (dollars per thousand cubic feet)	**5.09**	4.13	**5.34**	4.53

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea, and Libya. As of September 30, 2017, our Europe and North Africa operations contributed 17 percent of our worldwide liquids production and 14 percent of our worldwide natural gas production.

Earnings for Europe and North Africa operations decreased by $78 million in the third quarter but increased by $247 million in the nine-month period of 2017. The earnings decrease in the third quarter was primarily due to the absence of a 2016 net deferred tax benefit of $138 million resulting from a change in the U.K. tax rate enacted in September 2016. The earnings decrease was partly offset by higher crude oil and natural gas realized prices and lower DD&A, mainly due to reserve revisions.

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In addition to the factors discussed above, earnings increased in the nine-month period due to lower proved property impairments in the United Kingdom; a $41 million tax benefit in Norway, recognized in the second quarter of 2017; and lower production and operating expenses.

Average production increased 16 percent in the third quarter and nine-month period of 2017. The increase in the third quarter was mainly due to the resumption and ramp-up of production in Libya; new production from the Greater Britannia Area and Norway; lower unplanned downtime; higher Norway gas offtake; and improved drilling and well performance in Norway. In addition to these factors, lower planned downtime in Norway improved production in the nine-month period. The production increase in both periods was partly offset by normal field decline in Norway and the United Kingdom.

Asia Pacific and Middle East

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Net Income (Loss) Attributable to ConocoPhillips (millions of dollars)	$ **396**	(87)	**(1,540)**	(20)
Average Net Production				
Crude oil (MBD)				
Consolidated operations	**97**	100	**93**	98
Equity affiliates	**14**	15	**14**	14
Total crude oil	**111**	115	**107**	112
Natural gas liquids (MBD)				
Consolidated operations	**4**	8	**5**	8
Equity affiliates	**8**	8	**7**	8
Total natural gas liquids	**12**	16	**12**	16
Natural gas (MMCFD)				
Consolidated operations	**690**	712	**673**	737
Equity affiliates	**1,040**	948	**997**	883
Total natural gas	**1,730**	1,660	**1,670**	1,620
Total Production (MBOED)	**411**	408	**397**	398
Average Sales Prices				
Crude oil (dollars per barrel)				
Consolidated operations	$ **52.06**	44.27	**51.73**	40.33
Equity affiliates	**52.29**	44.78	**52.87**	41.94
Total crude oil	**52.10**	44.34	**51.88**	40.53
Natural gas liquids (dollars per barrel)				
Consolidated operations	**35.74**	25.84	**38.28**	27.66

Equity affiliates	**35.94**	25.12	**37.59**	27.25
Total natural gas liquids	**35.86**	25.50	**37.84**	27.46
Natural gas (dollars per thousand cubic feet)				
Consolidated operations	**4.63**	4.42	**4.87**	4.20
Equity affiliates	**4.51**	2.90	**4.28**	2.90
Total natural gas	**4.56**	3.55	**4.52**	3.50

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The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. As of September 30, 2017, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 49 percent of our worldwide natural gas production.

Earnings increased by $483 million in the third quarter and decreased by $1,520 million in the nine-month period of 2017. The earnings increase in the third quarter was primarily due to higher realized prices across all commodities and the absence of a third-quarter 2016 deferred tax charge of $174 million resulting from the change of our APLNG tax functional currency. Additionally, earnings were improved due to an $83 million reduction to a potential tax liability.

Earnings decreased in the nine-month period primarily due to a $2,384 million before- and after-tax charge for the impairment of our APLNG investment in the second quarter of 2017.

See the APLNG section of Note 5 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on the impairment of our APLNG investment.

Average production was essentially flat in the third quarter and nine-month period.

Other International

		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Loss Attributable to ConocoPhillips (millions of dollars)	$	**(20)**	(47)	**(77)**	(100)

The Other International segment consists of exploration activities in Colombia and Chile.

Losses from our Other International operations decreased $27 million in the third quarter and $23 million in the nine-month period of 2017. The reduction in losses in the third quarter was primarily due to the absence of 2016 rig stacking costs in Angola.

In the nine-month period of 2017, losses decreased due to lower rig stacking costs in Angola and reduced general and administrative expense in Senegal, partly offset by a $28 million after-tax charge for the cancellation of our Athena drilling rig contract in the first quarter of 2017.

Exploration Update

In July 2017, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. executed an Additional Contract for the exploration and exploitation of unconventional reservoirs in an area identified as the VMM-2 Block. As a result, ConocoPhillips Colombia Ventures Ltd. and Canacol Energy Colombia S.A. also executed a joint operating agreement. We have an 80 percent operated working interest in the block.

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Corporate and Other

		Millions of Dollars			
		Three Months Ended September 30		Nine Months Ended September 30	
		2017	2016	**2017**	2016
Net Loss Attributable to ConocoPhillips					
Net interest	$	**(176)**	(258)	**(603)**	(714)
Corporate general and administrative expenses		**(56)**	(54)	**(213)**	(211)
Technology		**20**	44	**29**	66
Other		**(115)**	(55)	**(312)**	(72)
	$	**(327)**	(323)	**(1,099)**	(931)

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased by $82 million in the third quarter and $111 million in the nine-month period of 2017, compared with the same periods of 2016, primarily due to impacts from the fair market value method of apportioning interest expense in the United States and lower interest on debt expense in the third quarter of 2017, partly offset by lower capitalized interest on projects.

Corporate general and administrative expenses increased by $2 million in the third quarter and nine-month period of 2017, compared with the same periods of 2016, primarily due to higher costs from certain compensation programs and the lease of an office building, partly offset by lower pension settlement expense.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, heavy oil and oil sands, as well as LNG. Earnings from Technology decreased $24 million in the third quarter and $37 million in the nine-month period of 2017, primarily due to lower licensing revenues, partly offset by reduced technology program spend.

The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment and premiums incurred on the early retirement of debt. Other expenses increased by $60 million in the third quarter and $240 million in the nine-month period of 2017. The expense increase in the third quarter was mainly due to a tax liability based on an updated assessment and premiums on our early retirement of debt, partly offset by lower restructuring charges. Premiums incurred on our retirement of debt in the second quarter further increased expenses in the nine-month period.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars	
	September 30 2017	December 31 2016
Short-term debt	**$ 1,331**	1,089
Total debt	**21,004**	27,275
Total equity	**30,712**	35,226
Percent of total debt to capital*	**41%**	44
Percent of floating-rate debt to total debt	**5%**	9

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, proceeds from asset sales, our commercial paper and credit facility programs, and our shelf registration statement. During the first nine months of 2017, the primary uses of our available cash were $6,594 million to reduce debt, $3,074 million to support our ongoing capital expenditures and investments program, $2,583 million net purchases of short-term investments, $2,045 million to repurchase common stock, $986 million to pay dividends, and a $600 million contribution to our domestic qualified pension plan. In the first nine months of 2017, we fully prepaid the remaining $1.45 billion balance on our term loan due in 2019 and reduced various debt instruments and notes by $4.8 billion. During the first nine months of 2017, cash and cash equivalents increased by $3.3 billion to $6.9 billion.

We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the Significant Sources of Capital section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, dividend payments and required debt payments.

Significant Sources of Capital

Operating Activities

Cash provided by operating activities was $4,596 million for the first nine months of 2017, compared with $2,960 million for the corresponding period of 2016. The increase was primarily due to higher realized prices across all commodities.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Production levels are impacted by such factors as the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. As we undertake cash prioritization efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves.

Investing Activities

Proceeds from asset sales for the first nine months of 2017 were $13.7 billion compared with $419 million for the corresponding period of 2016. All cash deposits and proceeds from asset dispositions are included in the Cash Flows From Investing Activities section of our consolidated statement of cash flows.

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included $11 billion in cash after customary adjustments and 208 million Cenovus Energy common shares. We have agreed not to transfer any of our Cenovus Energy common shares until six months from the closing date, after which we intend to decrease our investment over time through market transactions, private agreements or otherwise.

On July 31, 2017, we completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy Company. As of September 30, 2017, the total proceeds for the sale was $2.5 billion in cash after customary adjustments. On September 29, 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments.

On June 28, 2017, we signed a definitive agreement to sell our interests in the Barnett for $305 million in cash, subject to customary adjustments. The transaction is subject to specific conditions precedent being satisfied, including regulatory approval, and is expected to close in the fourth quarter of 2017.

For additional information on our dispositions and investment in Cenovus common shares, see Note 4 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements, Note 6 Investment in Cenovus Energy, and the Results of Operations section within Management s Discussion and Analysis.

Commercial Paper and Credit Facilities

At September 30, 2017, we had a revolving credit facility totaling $6.75 billion, expiring in June 2019. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

As of September 30, 2017, we had two commercial paper programs. The ConocoPhillips $6.25 billion commercial paper program is available to fund short-term working capital needs. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding at September 30, 2017 or December 31, 2016, under the ConocoPhillips nor the ConocoPhillips Qatar Funding Ltd. commercial paper program. We had no direct borrowings or letters of credit issued under the revolving credit facility. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at September 30, 2017.

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In the first quarter of 2017, Fitch and Standard & Poor s reflected an improvement in their outlook for our debt from negative to stable and affirmed our long-term debt rating at A-. After improving their outlook for our debt from negative to positive in the first quarter of 2017, Moody s Investor Services upgraded our long-term debt rating from Baa2 to Baa1 with a stable outlook in the third quarter in response to our debt reduction. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were downgraded, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At September 30, 2017 and December 31, 2016, we had direct bank letters of credit of $286 million and $304 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be required to post additional letters of credit.

Shelf Registration

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 11 Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

For information about our capital expenditures and investments, see the Capital Expenditures section.

Our debt balance at September 30, 2017, was $21 billion, a decrease of $6.3 billion from the balance at December 31, 2016.

In the first quarter of 2017, we made a prepayment of $805 million on our floating rate term loan facility due in 2019. In the third quarter of 2017, we prepaid the remaining balance of $645 million.

We redeemed $4.8 billion of debt during the nine-month period ending September 30, 2017 as described below.

In the second quarter of 2017, we redeemed $3.0 billion of debt across the following instruments:

6.65% Debentures due 2018 with principal of $297 million.
5.75% Notes due 2019 with principal of $2.25 billion (partial redemption of $1.7 billion).
6.00% Notes due 2020 with principal of $1.0 billion.

In the third quarter of 2017, we redeemed $1.8 billion of debt across the following instruments:

- 5.20% Notes due 2018 with principal of $500 million.
- 1.50% Notes due 2018 with principal of $750 million.
- 5.75% Notes due 2019 with principal of $550 million.

We incurred premiums above book value to redeem the debt instruments of $234 million and $50 million in the second and third quarter of 2017, respectively. These costs are reported in the Other expense line on our consolidated income statement.

In October 2017, we gave notice to make a partial redemption of $250 million on the $1.25 billion 4.20% Notes due in 2021. The prepayment will occur in the fourth quarter of 2017, and we expect to incur approximately $20 million in premiums above book value, subject to pricing related to this redemption when paid.

On a longer-term basis our debt target is less than $20 billion by year-end 2017 and $15 billion by year-end 2019. For more information on Debt, see Note 9 Debt, in the Notes to Consolidated Financial Statements.

Purchase obligations, which are contractual obligations primarily related to market-based contracts in our commodity business and agreements to access and utilize the capacity of third-party equipment and facilities, are expected to be $5 billion for the full year of 2017.

In January 2017, we announced a 6 percent increase in the quarterly dividend to $0.265 per share. The dividend was paid March 1, 2017, to stockholders of record at the close of business on February 14, 2017. In May 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid on June 1, 2017, to stockholders of record at the close of business on May 15, 2017. On July 12, 2017, we announced a quarterly dividend of $0.265 per share. The dividend was paid September 1, 2017, to stockholders of record at the close of business on July 24, 2017. On October 6, 2017, we announced a quarterly dividend of $0.265 per share payable December 1, 2017, to stockholders of record at the close of business on October 16, 2017.

On November 10, 2016, our Board of Directors authorized the purchase of up to $3 billion of our common stock over the next three years. During the first quarter of 2017, our Board of Directors approved an increase in the existing share repurchase authorization to a total of $6 billion, with an expectation of $3 billion occurring in 2017 and the remaining $3 billion allocated to 2018 and 2019. Since our share repurchase program began in November 2016, we have repurchased 47.4 million shares at a cost of $2.2 billion through September 30, 2017.

During the third quarter of 2017, we made a $600 million contribution to our domestic qualified pension plan, which is included in the Other line in the Cash Flows From Operating Activities section of our consolidated statement of cash flows. This additional contribution mitigates the need for contributions in future quarters. It also significantly lowers our domestic pension deficit which will reduce future premiums charged by the Pension Benefit Guaranty Corporation.

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Capital Expenditures

	Millions of Dollars Nine Months Ended September 30 **2017**	 2016
Alaska	$ **636**	702
Lower 48	**1,234**	992
Canada	**180**	553
Europe and North Africa	**657**	801
Asia Pacific and Middle East	**316**	700
Other International	**17**	81
Corporate and Other	**34**	41
Capital expenditures and investments	$ **3,074**	3,870

During the first nine months of 2017, capital expenditures and investments supported key exploration and development programs, primarily:

- Oil and natural gas development and exploration activities in the Lower 48, including Eagle Ford, Bakken, and the Permian Basin.
- Alaska activities related to development in the Western North Slope, Greater Kuparuk Area and the Greater Prudhoe Area.
- Development activities, in Europe, including the Greater Ekofisk Area, Clair Ridge, Aasta Hansteen, and Heidrun.
- Continued oil sands development and appraisal activities in liquids-rich plays in Canada.
- Appraisal drilling in deepwater Gulf of Mexico.
- Continued development in Malaysia, Indonesia, China and Australia; appraisal activity in Australia; and exploration activity in Malaysia.

Full-year guidance for capital expenditures has been lowered to $4.5 billion.

Contingencies

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For information on other contingencies, see Note 12 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Legal Matters

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. For a discussion of the most significant of these environmental laws and regulations, including those with associated remediation obligations, see the Environmental section in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 63 65 of our 2016 Annual Report on Form 10-K.

We occasionally receive requests for information or notices of potential liability from the Environmental Protection Agency (EPA) and state environmental agencies alleging that we are a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain waste attributable to our past operations. As of September 30, 2017, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

At September 30, 2017, our balance sheet included a total environmental accrual of $182 million, compared with $247 million at December 31, 2016, for remediation activities in the United States and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation and precursors for possible regulation that do or could affect our operations include the EPA s announcement on March 29, 2010 (published as Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010)) and the EPA s and U.S. Department of Transportation s joint promulgation of a Final Rule on April 1, 2010, that trigger regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.

For other examples of legislation or precursors for possible regulation and factors on which the ultimate impact on our financial performance will depend, see the Climate Change section in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 65 66 of our 2016 Annual Report on Form 10-K.

NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, Leases, and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. We plan to adopt ASU No. 2016-02 effective January 1, 2019, and continue to evaluate the ASU to determine the impact of adoption on our consolidated financial statements and disclosures, accounting policies and systems, business processes, and internal controls. While our evaluation of ASU No. 2016-02 and related implementation activities are ongoing, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures. For additional information, see Note 21 New Accounting Standards, in the Notes to Consolidated Financial Statements.

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CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by the words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, seek, should, will, wo projection, forecast, goal, guidance, outlook, effort, target and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices, including a prolonged decline in these prices relative to historical or future expected levels.

The impact of recent, significant declines in prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.

Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.

Inability to maintain reserves replacement rates consistent with prior periods, whether as a result of the recent, significant declines in commodity prices or otherwise.

Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.

Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.

Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.

Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and natural gas liquids.

Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development; failure to comply with applicable laws and regulations; or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.

Failure to complete definitive agreements and feasibility studies for, and to complete construction of, announced and future exploration and production and LNG development in a timely manner (if at all) or on budget.

Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, terrorism, cyber attacks or infrastructure constraints or disruptions.

Changes in international monetary conditions and foreign currency exchange rate fluctuations.

Reduced demand for our products or the use of competing energy products, including alternative energy sources.

Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
Liability resulting from litigation.
General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; and other political, economic or diplomatic developments.
Volatility in the commodity futures markets.
Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
Competition in the oil and gas exploration and production industry.
Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
Our inability to execute, or delays in the completion, of any asset dispositions we elect to pursue.
Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions or that such approvals may require modification to the terms of the transactions or the operation of our remaining business.
Potential disruption of our operations as a result of asset dispositions, including the diversion of management time and attention.
Our inability to deploy the net proceeds from any asset dispositions we undertake in the manner and timeframe we currently anticipate, if at all.
Our inability to liquidate the common stock issued to us by Cenovus Energy as part of our sale of certain assets in western Canada at prices we deem acceptable, or at all.
Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
The operation and financing of our joint ventures.
The ability of our customers and other contractual counterparties to satisfy their obligations to us.
Our inability to realize anticipated cost savings and expenditure reductions.
The factors generally described in Item 1A Risk Factors in our 2016 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the nine months ended September 30, 2017, does not differ materially from that discussed under Item 7A in our 2016 Annual Report on Form 10-K.

Item 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of September 30, 2017, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of September 30, 2017.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the third quarter of 2017 and any material developments with respect to matters previously reported in ConocoPhillips 2016 Annual Report on Form 10-K. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to U.S. Securities and Exchange Commission regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain or have subsequently become a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

Matters previously reported ConocoPhillips

A Judgment and Consent Decree was entered on December 7, 2016, by the South Central Judicial District Court in Burleigh County, North Dakota against Burlington Resources Oil & Gas Company LP and ConocoPhillips Company resolving alleged violations of the state s air pollution control laws. The North Dakota Department of Health was the Plaintiff in this matter. The Consent Decree requires the companies to implement a specified program to inspect and repair as necessary its facilities in North Dakota and to pay a penalty. The parties agreed to a penalty of $193,100 and the companies paid that amount in the third quarter, resolving this matter.

Matters previously reported Phillips 66

In October 2016, after Phillips 66 received a Notice of Intent to Sue from Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Agency for alleged violations of wastewater requirements at the Wood River Refinery. The settlement involves certain capital projects and payment of $125,000. After the settlement was filed with the Court for final approval, the Sierra Club sought and was granted approval to intervene in the case. Phillips 66 is working to obtain Court approval for the settlement.

Item 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Item 1A of our 2016 Annual Report on Form 10-K.

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Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS
Issuer Purchases of Equity Securities

						Millions of Dollars
Period	Total Number of Shares Purchased*		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**		Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs**
July 1-31, 2017	6,952,156	$	43.61	6,952,156	$	4,496
August 1-31, 2017	7,849,928		44.42	7,849,928		4,147
September 1-30, 2017	6,899,880		46.14	6,899,880		3,829
Total	21,701,964	$	44.71	21,701,964	$	3,829

** There were no repurchases of common stock from company employees in connection with the company s broad-based employee incentive plans.*

*** On November 10, 2016, we announced a share repurchase program for up to $3 billion of common stock over the next three years. On March 29, 2017, we announced plans to double our share repurchase program to $6 billion of common stock over the next three years. Acquisitions for the share repurchase program are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.*

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Item 6. EXHIBITS

12*	Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

** Filed herewith.*

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONOCOPHILLIPS

/s/ Glenda M. Schwarz
Glenda M. Schwarz

Vice President and Controller

(Chief Accounting and Duly Authorized Officer)

October 31, 2017